U.S. House of Representatives
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Steve Marshall
President, BP Exploration (Alaska) Inc.

Written Testimony

My name is Steve Marshall and I am President of BP Exploration (Alaska) Inc. (BPXA). BPXA is the operator of the largest oil field in North America – Prudhoe Bay on Alaska's North Slope. The Prudhoe Bay field consists of, among other things, over 1100 production wells, approximately 1500 miles of pipelines, multiple processing facilities (including the largest gas processing plant in the world) and living quarters for our employees.

I will discuss BPXA's Prudhoe Bay oil field operations and the actions taken on August 6th to begin the orderly shutdown of Prudhoe Bay - a decision I believe was the best option in order to avoid the risk of an oil spill. I will also present some background material on the corrosion prevention programs in the field.

Prudhoe Bay

The Prudhoe Bay field is located 650 miles north of Anchorage and 400 miles north of Fairbanks. It is 1200 miles from the North Pole and 250 miles north of the Arctic Circle. Pump Station 1, the beginning of the Trans Alaska Pipeline System (TAPS), is located within the perimeter of the Prudhoe Bay field. For additional detail on Prudhoe Bay operations please refer to Exhibit 1 in the appendix.

Prior to 2000, the Prudhoe Bay field comprised the East Operating Area (EOA), operated by Atlantic Richfield Company (ARCO), and the West Operating Area (WOA), operated by BPXA. Upon acquisition of ARCO by BP, BPXA became the sole operator of the Greater Prudhoe Bay (GPB) field. Although BPXA operates the field, a total of nine companies have a so-called "working interest" in the field leases. The costs and production are shared amongst the working interest owners, according to their ownership.

Alaska's Leadership Challenge

I took over as President of BPXA in September of 2001. I assumed this responsibility at a critical juncture for the Company as it emerged from a period of low oil prices. There were a number of employee issues and management challenges presented by my new duties. Earlier in my career, I spent five (5) years on the Slope. With the knowledge I gained during that time, I came into the top job with some very definite goals in mind.

First and foremost, I wanted to re-instill pride in our operations through improving both the physical facilities in the oil field and our operating practices. I also wanted to reaffirm the spirit of cooperation and teamwork amongst all BPXA employees and contractors – a spirit that promoted excellence when I worked in Alaska during the 1970's and 80's. The opportunity to pursue this primary goal presented itself shortly after my arrival in Alaska.

During the years immediately preceding my return to Alaska, the BP and contractor workforces raised concerns to the media, Congress and others outside of BP. An internal project team was organized to evaluate the validity of the issues raised through these avenues and also to survey and review the concerns of all BP employees and systems in place on the North Slope. This project is referred to and was documented in the Operations Review Team (ORT) report which was issued in September of 2001. This ORT report confirmed that there were legitimate problems which existed in the field with maintenance items and some operational integrity issues.

I was asked to move to Alaska and provide oversight to the effort to resolve the issues identified in the ORT report, as well as resurrect trust and respect between employees and BP management. The results of the ORT report were shared with Congress and the public - good and bad. The corrective action program was open with employees and members of Congress.

Beyond the ORT report and other efforts to ensure that workforce concerns are heard and acted upon, I have made several key philosophic changes during my tenure - some of which are still a "work in progress":

- A philosophy of complete transparency in our dealings with employees, contractors and stakeholders. This has resulted in a number of systems that allow for contractors and employees to raise concerns about safety and integrity.

- A philosophy of constant peer challenge that has resulted in several outside reviews of our operations conducted by experts from within and outside the BP Group – and improvements to our operations.

- A philosophy of continuous improvement that caused me to re-think my organization after the March spill – and reorganize so that all corrosion and integrity programs now reside under a Technical Directorate. The key feature of Technical Director is that it is independent of line operational management in order to improve our performance and get a more direct “line of sight” on these key programs. The “before and after” organizations are shown in Exhibit 2.

Recent Problems with OTL Integrity

In March of 2006, BPXA discovered a leak along the Gathering Center (GC) Oil Transit (OT) 21 line in the Western Operating Area (Exhibit 3). This is a 34” line that carries sales quality crude oil from a central gathering center for ultimate delivery into TAPS at pump station 1. The leak was approximately 5,000 barrels, the largest spill ever on the Alaskan North Slope.

Shortly thereafter, the U.S. Department of Transportation (DOT) issued a Corrective Action Order (CAO) to BPXA ordering it to perform In-Line Inspection (ILI) or “smart pig” tests along with other inspection methods along both the Western and Eastern Oil Transit Lines (OTLs). There were a number of complex technical issues to resolve before the tests could be conducted, including developing a solution for managing the solids generated during the maintenance pigging operations that precede smart pigging operations to insure a clean pipeline.

BPXA began pigging operations along the Lisburne OTL in June. ILI of the Lisburne OTL showed good results and affirmed our confidence that the lines were fit for service. The pigging also revealed that the line contained very little sediment.

BPXA began pigging operations along the Eastern OTL in early July, which also revealed very little sediment (10 bbls) in the line contrary to earlier estimates. Analyses of these "smart pig" inspections were received on Friday, August 4 and indicated sixteen (16) significant anomalies at twelve (12) different locations along the upstream segment of the Eastern OTL. BPXA began immediate physical and ultrasonic testing of these anomalies and verified the presence of additional corrosion. Early on August 6, BPXA's inspections revealed insulation staining along a segment of the Eastern OTL. With the knowledge of these results, BPXA immediately shut down production at Flow Station (FS) 2 as a precautionary measure, and BPXA technicians subsequently discovered a small leak after close visual inspection along the FS-2 to FS-1 pipeline segment.

The smart pig results along the Eastern OTL were unexpected. Because the exact cause of the corrosion mechanism was unknown, BPXA was concerned over the condition of both the Eastern and Western OTLs. Thus, BPXA took the prudent step on the morning of August 6 of announcing our intent to systematically shut-down both sides of the Prudhoe Bay field until existing inspection data could be further assessed and verified with follow up inspections.

Some have questioned whether BPXA made a rash decision to shut down the field over a small leak. To me, as President of BPXA, the decision to shut-down was a reaffirmation of BP's values and was the responsible thing to do. We took this step to prevent a potential release from occurring.

In light of these incidents, many have alleged that BPXA's inspection and maintenance program was inadequate. Given our almost 30 year performance history and our existing programs, we believed we had an effective corrosion management program in place. Clearly, recent events have shown that our program did not detect or prevent the type of pitting corrosion identified here. We are examining and analyzing this data closely to ensure that we apply this learning to improve our program.

BP Corrosion Prevention Program for the North Slope

Corrosion is the natural degradation of a material like steel pipe that results from a reaction with its environment. While corrosion cannot be eliminated, it can be effectively managed through a combination of monitoring and mitigation treatments. The goal of corrosion mitigation programs is to control corrosion rates to acceptable levels.

Corrosion rates are not static, however, and they can increase or decrease depending on fluid properties or changes in conditions that affect the efficacy of corrosion inhibitors. For that reason, locations that are prone to corrosion damage, or where damage has been identified, are inspected as often as every three to six months.

BPXA uses pigging, ultrasonic testing (UT), visual inspections, corrosion inhibitors and other techniques as appropriate for each individual oil field's characteristics. We employ a risk-based management program whereby resources and activities are concentrated in areas where corrosion is most likely to occur. Exhibits 4 and 5 describe the operations of a gathering center in producing, separating out gas and water, and pumping oil, and they also show a graphical representation of a producing field.

As oil production declined and water production increased, the risk of corrosion has increased. BPXA's program has been modified and enhanced to meet that challenge in recent years. Indeed, the 2006 annual budget for BPXA's corrosion monitoring and mitigation program is $74 million, an increase of 15 percent from 2005, and 80% from 2001. As Exhibit 6 demonstrates, corrosion management "spend" has increased significantly over the last 5 years despite the reduction in Prudhoe Bay oil production volumes.

This corrosion program is designed to continuously mitigate corrosion in the upstream facilities (well lines, flow lines and gathering centers) which has historically had the most corrosion issues. By inhibiting corrosion in the upstream facilities, the downstream facilities (such as the OTLs) are also protected.

The BPXA program is designed for (1) the "carryover" of corrosion chemicals through the gathering centers (or flow stations, as they are called in the EOA) to protect the OTLs; and (2) monitoring and inspection of these lines to track any changes that indicated a problem.

Clearly, in hindsight, this prevention monitoring and inspection program for the OTLs was not sufficient to identify changed corrosion rates that appear to have resulted from changing conditions in the field.

The following section describes the Corrosion Prevention Program for the North Slope in more detail.

Inhibition

A key element of the corrosion prevention program is widespread continuous inhibitor injection. In short, the best way to address corrosion is to prevent it from happening in the first place. Our commitment to effectively managing corrosion on the North Slope is reflected in our corrosion inhibitor injection rates. Exhibit 7 is a diagram of the inhibitor concentrations and the corresponding corrosion rates achieved as measured by corrosion coupons.

We continuously monitor the effectiveness of the inhibition programs with corrosion coupons and electrical resistance (ER) probes. The ER probes take readings every 4 hours of the corrosion potential of the fluids and allow us to make adjustments to corrosion inhibitor injection rates on a weekly basis. Exhibit 8 is a typical configuration of a corrosion coupon and ER probe.

We have not been satisfied with simply maintaining the *status quo*. We conduct an on-going and very active inhibitor research program outlined in Exhibit 9. This inhibitor research program enables us to identify new inhibitor formulations to improve our corrosion management program.

Monitoring and Inspections

BP's North Slope pipeline monitoring and inspection program incorporates combinations of ultrasonic, radiographic, and guided wave inspection techniques. In addition, we utilize coupon monitoring, smart pigging, leak detection systems and surveillance by personnel to provide integrity assurance and maintain safe operations. BPXA's overall annual inspection program consists of conducting inspections at about 100,000 locations in Greater Prudhoe Bay. Of these inspections, approximately 60,000 are for internal corrosion inspection and approximately 40,000 are for external corrosion inspection.

It is important to note that most pipelines on the North Slope are above-ground pipeline, in contrast to other oil fields in other parts of the United States (where pipes are typically buried). This design makes it possible to use direct measurement techniques to assess the integrity of these pipelines. These types of “direct assessments” are recognized as an effective alternative to ILI methods.

Ultrasonic, radiographic, and guided wave testing are used to assess the condition of the lines and to trigger further action as necessary. Ultrasonic Testing (UT) involves the use of a high frequency sound wave to produce a precise measurement of the thickness of a material. Our UT inspections are not simply one reading at one location on the pipe. Rather, they are an inspection of the full circumference of the pipe over a one foot length. So when we count one UT inspection, it is really hundreds of individual readings at that location. Radiographic testing literally provides an x-ray image of the line, and allows us to “see” both the internal and external condition of the line. Guided wave inspections utilize a new technology that allows us to perform an assessment of buried and / or encased pipe.

We also use corrosion coupons (see Exhibit 8) throughout our operations in order to obtain additional information about any corrosive conditions that might exist in our systems that escaped other inhibition and monitoring programs. The majority of our coupons are read on a three to four month basis.

Important components of pipeline inspections also include regular visual inspections and the use of Forward Looking Infrared (FLIR) devices. FLIR technology is used to spot heat signatures of crude oil and is especially useful during winter months.

Mitigation of Corrosion

In the design of pipelines, many corrosion mitigation methods are considered. The selection of material from which to manufacture pipe, such as corrosion resistant alloys like stainless or low carbon steel, is one consideration. Another option is the use of various coatings and linings that provide pipelines protection against corrosive agents.

Technology used to protect metal structures from corrosion includes cathodic protection, a technique that is usually used in buried pipelines and takes advantage of electrochemical properties to reduce a metal structure's corrosion potential.

Mitigation also involves the application of corrosion inhibitors and biocides in conjunction with preventative maintenance such as pigging and physical repair of damage.

BPXA runs approximately 370 maintenance pigs per year on the North Slope. (See Exhibit 10 for detail regarding pigging operations). Maintenance pigging is conducted either because of mechanical issues or because corrosion monitoring suggests it. The frequency of maintenance pigging is specific to each pipeline and varies significantly across the North Slope and the industry. For example, the Northstar oil pipeline is pigged every two weeks to prevent paraffin buildup. The OTLs, on the other hand, do not experience the same build-up of sediments.

External corrosion is mitigated by removal of the source for the water, drying, cleaning and buffing of the damage area and application of new insulation and/or coatings. If external corrosion limits the integrity of the pipeline, then repair techniques are used such as sleeves, clock springs, clamps and or composite wraps.

If the programs are so good, what happened?

Clearly, something went wrong. We will continue to try to understand the physical mechanism behind the OTL leaks. Currently, our understanding is as follows:

The recent leaks were on the oil transit lines, which are the last step in the process before TAPS. General corrosion and pitting in the OTLs were monitored by corrosion coupons on a quarterly basis, and have consistently shown very low corrosive conditions in these lines, always below the BP targeted wall thickness loss of less than .002 inches per year. Exhibit 11 shows coupon results in the OTLs. Every single corrosion coupon for more than a decade, on both the EOA and WOA OTLs, met our acceptance criteria, and none of them indicated the problem that BPXA recently discovered. In spite of their low corrosivity, the OTLs were included in our on-going UT monitoring program. Multiple locations on the OTLs were monitored on a routine basis, and have consistently revealed corrosion to be managed effectively on these lines.

The first indication of a growth in corrosion came from the corrosion monitoring program in the facilities upstream of the WOA OTLs. An increase in facility corrosion upstream of the WOA OTLs, while not alarming, caused us to perform additional UT inspections of the OTLs. The results of these inspections led us to schedule another ILI of the WOA OTL for mid- 2006. Unfortunately, the March release occurred before that pig run was conducted.

It has been misreported that the OTLs have wide-spread corrosion. In fact, no evidence of general corrosion (i.e. wall loss throughout the pipe) along the OTLs has been found. If there was, it would have been quickly detected by our monitoring programs. Instead, the OTLs have widely spaced, mostly isolated dime-sized pits about 5 to 10 feet apart. It appears that the corrosion is more serious on the upstream segments of these lines, which have the lowest flow velocities.

Why wasn't the pitting corrosion detected by BP's monitoring program? BP had an active inspection program for these lines, but the isolated pits were too widely spaced to be detected by that program. For example, there was an inspection site adjacent to the site where a leak occurred. The inspection did not detect any corrosion – just a few feet away from a pit.

We initially believed that the corrosion along the WOA had developed due to certain operational changes in the WOA, and that the EOA was not similarly affected. Our initial inspections of the EOA line appeared to confirm this. However, these conclusions were premature and made before the latest inspections were completed. The inspection of the EOA OTL revealed that the pattern of corrosion damage is similar in both the EOA and WOA, although the precise corrosion mechanism remains under study.

Despite years of coupon monitoring, UT inspection and the 1990 and 1998 smart pig runs that indicated no serious corrosion problems with the transit lines, a serious corrosion problem did develop. Regular maintenance pigging might have prevented the current problem from occurring. Our corrosion management system will be adjusted to an even more rigorous program to address these issues.

The Coffman and Baxter Reports

In recent weeks, there has been a lot of discussion and debate about both sets of outside review and critique – the Baxter and Coffman reports. I feel it is important to set the record straight on both reports.

John Baxter is the top-ranking engineering authority within the BP group. John was asked twice to come to Alaska, in 2005 and 2006, to review the BPXA corrosion management program. These requests reflect both BP's philosophy of constant peer challenge and my personal view that even good programs benefit from outside perspectives. John's reports were very fair in their assessment of both the good and bad aspects of the Alaska corrosion programs. The reports were also used extensively by my team to make improvements in the program.

For instance, one of the 2005 criticisms went to John's concern that despite my desire and directive to increase investment in facilities maintenance and integrity on the Slope, there remained a "culture of conservatism" for making these investments, as a result of low oil price years in the late 1990's. This comment was taken to heart by my leadership team and acted on, and indeed the 2006 Baxter Report noted measurable improvements on this area.

Recent mention has been also been made of the annual reports that have been submitted by an outside engineering firm, Coffman Engineers. Coffman Engineers is retained by the State of Alaska to review BPXA's annual report on corrosion management for the State of Alaska. While praising BPXAs program, Coffman Engineers also has noted deficiencies in BPXA's program. There appears to be some implication that the noted deficiencies played a role in the recent pipeline incidents. However, Coffman did not specifically discuss the oil transit lines in any of its reports.

Previous Coffman reports have noted there were isolated pockets of accelerated corrosion in BPXA's North Slope infrastructure. When discussing internal corrosion on oil lines, the Coffman reports focus attention on the "production system" of well lines and flow lines, the "three-phase" lines that carry a mix of oil, water and gas. These are the lines where corrosion is more of a known threat than in the transit lines that carry "processed oil".

While there were areas in Coffman's reports recommending additional inspection and maintenance activities, on balance they offered support for the efficacy of BPXA's corrosion management program. Excerpts from recent Coffman reports are shown below:

- The 2003 report states: "From a global perspective of oil and gas production, Greater Prudhoe Bay (GPB) and related facilities have an aggressively managed corrosion control program. This suggests an adequate long-term commitment to preserving facilities for future production and sensitivity to environmental consequences."
- The 2004 report credits BP with transparency and candor, and for maintaining a corrosion program in which there is no "acceptable" risk. It said BP's program "is effective and exceeds common industry practice," and that "Corrosion in most of the pipeline system has been reduced to a negligible level."

Path Forward for North Slope Pipeline Infrastructure

BPXA's incident analysis is still underway, but we have already taken steps to characterize the problem and assess the integrity of all the OTL lines. This information has been submitted to the Office of Pipeline Safety (OPS), whose staff is currently reviewing it. We also have outside experts who are reviewing the data and who will provide independent opinions about its adequacy.

We have been working in cooperation with OPS to ensure the safety and integrity of these systems. We pledge to continue working in cooperation with DOT and other interested stakeholders to ensure that these lines, and all our pipeline operations on the North Slope, are operated to a high standard of operational excellence.

Now we must focus our attention on the future – and what we will do to mitigate the risk of future leaks occurring in these oil transit lines. We have committed to undertake seven key actions:

First - Run an in-line inspection tool in each of the Prudhoe Bay Oil Transit Lines that are returned to service.

Second - Confirm through testing the exact corrosion mechanism that caused this problem and modify our corrosion control programs accordingly.

Third - Implement maintenance pigging in all Oil Transit Lines.

Fourth - Include all BP operated Oil Transit Lines on the North Slope into DOT's Pipeline Integrity Management (PIM) Program. This will cover all 122 miles of BP Oil Transit Lines in Alaska – not just those in the Prudhoe Bay field.

Fifth - Replace 16 miles of WOA / EOA oil transit lines with smaller (higher-velocity) lines to help ensure this problem does not recur. The estimated cost of this is in excess of $150 million.

Sixth - The BPXA organizational structure has been changed with the addition of a Technical Director to provide independent assurance of our integrity management efforts.

Seventh - Increase Prudhoe Bay major maintenance spending to $195 million in 2007, a nearly four fold increase from 2004 spending levels. This increase is in addition to the investment in replacement pipe.

In addition to these physical changes, we remain committed to work collaboratively and proactively with the DOT, State regulators, and other stakeholders.

Business Resumption Plan

BPXA is also actively working to restore full production in the Greater Prudhoe Bay field. The following serves as a review of those activities.

Western Operating Area

BPXA has conducted more than 4,876 UT tests of the Western Operating Area OTLs since the August 6th announcement. These subsequent inspection results have not indicated any wall thickness loss greater than 39%. This accelerated rate of inspections – and the resulting data – allowed BPXA to make the decision to continue operating the WOA and cease the orderly shut down originally announced on August 6. We have continued these inspections since that August 11 decision and will not cease the activities until we conduct a smart pig run (scheduled for late October or early November).

In addition, BPXA has begun a surveillance effort that includes daily over-flights using infrared cameras, as well as the use of hand-held infrared cameras on the ground. The cameras can detect small leaks by sensing changes in pipeline surface temperatures. Two vehicles with spill response equipment and carrying observers with infra-red leak detection equipment are patrolling the line 24 hours a day. They are teamed with pipeline walkers who will visually inspect the line ten (10) times a day.

Eastern Operating Area

Since August 6, over 12,000 UT inspections have occurred on this line – nearly 25% of the line. We are averaging 200 to 300 inspections per day. About 160 workers are dedicated to this inspection effort.

We are currently focusing inspections on the 34" segment that runs from FS-1 to Skid 50 (see Exhibit 3). If the inspection results show that the line has integrity, we will request permission from the DOT to re-start that line. We are currently working through a process with DOT to make that request once we can provide assurance that the line can be safely re-started and pigged. We expect to make that request in the near future. Restart will allow us to quickly run both maintenance and smart pig these lines, in line with the DOT CAO.

Regarding the leak along the FS-2 transit line, the estimated 23 barrels of oil spilled has been cleaned up. The line currently holds about 13,000 barrels of crude. Metal sleeves have been installed on those sections of the transit line with severe corrosion. BPXA has submitted a plan to the U.S. Department of Transportation (DOT) for de-oiling this segment of line.

Concurrent with our inspection activities and in case these activities indicate that the lines are not fit for service, by-pass options are being pursued to restore as much production as possible in an environmentally safe manner. The focus is largely on the EOA and includes new options to divert production from each of the existing Flow Stations to Skid 50 (see Exhibit 3).

- The production from FS-2 is being engineered to route to the Endicott production line through new piping.
- The production from FS-1 is being engineered to route to the Endicott production line through new piping.
- The production from FS-3 is being engineered to route through Drill Site 15 and then to a jumper into the Lisburne OTL.

We expect work on these options to be complete by the end of October.

All of this work is taking place as BPXA prepares for ultimate replacement of the 16 miles of WOA/EOA oil transit lines. Sixteen (16) miles of pipe has been ordered from US mills and is expected on the slope during the fourth quarter. We are hopeful that work can be completed during the winter construction season.

While many of the circumstances surrounding the incidents at Prudhoe Bay are known there is much more that needs to be done to fully understand the corrosion mechanism we experienced. These results will be known in due course and will be shared in a fully transparent way. In the meantime, BPXA is committed to restoring full production to the EOA as soon as we are confident it can be done in a safe and environmentally responsible way.

New Pipeline Safety Regulations

Historically, certain pipelines that operate at low stress were exempt from U.S. DOT oversight. This exemption applied to onshore pipelines such as oil transit lines on the Alaskan North Slope.

However, since the March 2, 2006 spill from BP's Western OTL (a low-stress system); DOT has proposed a rule to revise the low-stress exemption. Upon completion of its rulemaking process, it is likely that any low-stress pipeline that is in an environmental high consequence area will become a regulated pipeline under DOT jurisdiction. These proposed regulatory changes are strongly supported by BP.

Employee Concerns

I'd like to conclude by returning to a priority for BPXA that was discussed at the beginning of my testimony-addressing and acting upon employee concerns. A number of people have raised questions and concerns about our corrosion inspection, monitoring and prevention program. Sometimes these concerns have been voiced inside the company. Sometimes, they have been taken to regulators or to the media.

I view every employee concern as an opportunity to address a problem. I don't care how or with whom they are raised. I just want to know about them. We need the input of our workers to continuously improve and be the best business we can be.

BP feels the same way. Harassment, intimidation, retaliation and discrimination against workers who raise concerns are not tolerated within BP.

We have a number of channels through which workers can raise concerns. In addition to just the normal line management channels, we have employee-run safety committees, we have a worldwide anonymous program called Open Talk, and in Alaska we have other, confidential methods for employees to communicate workplace concerns. We also track employee satisfaction and concerns via a People Assurance Survey conducted annually. The results from the 2006 survey indicate a 13% improvement year over year for our Slope-based workforce.

BP has a track record of acting on employee concerns. Over the last several years employee safety committees have raised, and we have jointly addressed over 600 safety concerns. They range from the quality of vehicle headlights to challenging whether the injection of fluids into disposal wells was appropriate.

More importantly, BP has investigated and addressed concerns raised about our corrosion inspection, monitoring and inspection program.

During the summer of 2002 a BP employee received two anonymous calls alleging falsification of corrosion inspection reports by a handful of contract workers. BP brought in an outside firm, audited the work performed on the program year-to-date, and determined that a small percentage of inspections had indeed been falsified. The investigation also called into question our inspection contractor's quality assurance program.

Our inspection contractor dismissed the workers responsible for falsifying inspection reports and three months later, when the inspection contract was up for renewal, we brought in a new company to do this work.

As another example, in 2004, after receiving allegations of harassment, intimidation and retaliation by a BP corrosion program manager we brought in an outside law firm, Vinson and Elkins (V&E) to conduct an investigation. Vinson and Elkins found evidence of intimidating behavior that had made some corrosion workers reluctant to raise health and safety concerns.

We acted on the recommendation of V&E and transferred the manager in question outside Alaska into a technical consulting role.

When concerns were raised about whether BPXA had inappropriately influenced edits made in an Alaska state review of the company's corrosion management program, BP again brought in an outside law firm to investigate.

The investigation found no evidence of improper behavior on the part of the company or its employees.

Conclusion

Bob Malone, Chairman and President of BP America recently announced a number of actions to ensure that our businesses are run in a manner that meets our expectations and yours. I would like to highlight the following actions that impact operations in Alaska:

1. BP America has retained three of the foremost experts in the world around corrosion and infrastructure management to evaluate and make recommendations for improving the corrosion management program in Alaska.

2. BP has added an additional $1 billion to the $6 billion already earmarked to upgrade all aspects of safety at its US refineries and for integrity management in Alaska. Over $550 million (net) will be spent on integrity management improvements in Alaska over the next two years.

3. Former U.S. District Court Judge Stanley Sporkin has been appointed as an independent ombudsman reporting directly to Bob Malone and he has been asked to conduct a review of all worker allegations that have been raised on the North Slope since 2000.

4. Mr. Malone has established an Operational Advisory Board composed of fifteen senior business leaders in BP America to advise him on safety,

operational integrity and compliance and is building a team of internal experts on employee safety, process safety, operational integrity, and compliance and ethics to assist him.

5. An external advisory board is being recruited to assist in monitoring BP's US businesses with particular focus on safety, operational integrity, compliance and ethics.

I welcome these actions and see them as a way to improve how we operate our business.

In closing Mr. Chairman, since March, we identified an unexpected gap in our corrosion control program, and we will correct it. In the future, we will have a better system to protect our pipelines and we have already gained important new operating knowledge.

I deeply regret the problems caused by the situation we discovered. But we will emerge stronger and more knowledgeable as a result of this challenge.

EXHIBIT 1

Fact Sheet Prudhoe Bay

Background
The Prudhoe Bay field is the largest field in North America and the 18th largest field ever discovered worldwide. Of the 25 billion barrels of original oil in place, more than 13 billion barrels can be recovered with current technology.

Prudhoe Bay field was discovered on March 12, 1968, by ARCO and Exxon with the drilling of the Prudhoe Bay State #1 well. A confirmation well was drilled by BP Exploration in 1969. The next 8 years saw frenetic activity as ARCO, BP, Exxon, and other companies with lease holdings in the vicinity worked to delineate the reservoir, resolve equity participation, and put together an initial infrastructure. Prudhoe Bay came on stream in June 20, 1977, rapidly increasing production until the field's maximum rate was reached in 1979 at 1.5 million barrels per day. This rate was maintained until early 1989, and is currently declining by 10% per year. Production totaled approximately 475,000 barrels per day on January 1, 2004. More than 10 billion barrels have already been produced.

Prior to 2000 the Prudhoe Bay field was comprised of the East Operating Area, operated by ARCO, and the West Operating Area, operated by BP Exploration. Upon acquisition of ARCO by BP and sale of ARCO Alaska assets to Phillips Petroleum, the two operating areas were consolidated and BP became the sole operator of Greater Prudhoe Bay. Although BP operates the field, a total of nine companies have an interest in the field leases. The profits and costs are shared amongst the owners, according to their ownership.

Ownership
BP Exploration (Operator), 26%
ConocoPhillips Alaska Inc., 36%
ExxonMobil, 36%
Others, 2%

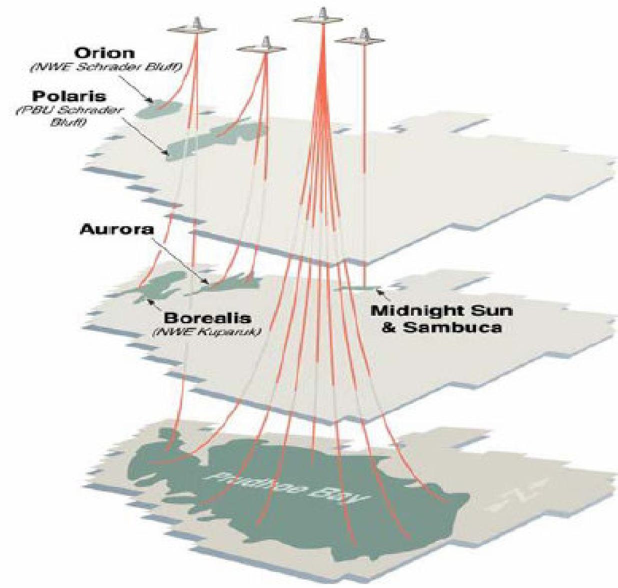
Greater Prudhoe Bay Fast Facts	Discovered	1968	
	Production started	1977	
	Oil production wells	1114	
	Participating field area (including satellites)	213,543 acres	
	Daily production (thousands)	475,000 bbls/day	
	Total cumulative production (1/1/05)	<u>BP Net</u> 4395	<u>Gross</u> 10,839
Midnight Sun Fast Facts	Production started	1998	
	Oil production wells	2	
	Participating field area (including satellites)	3,112 acres	
	Daily production (thousands)	5,500 bbls/day	
Aurora Fast Facts	Production started	2000	
	Oil production wells	10	
	Participating field area (including satellites)	7,519 acres	
	Daily production (thousands)	9,000 bbls/day	
Orion Fast Facts	Production started	2002	
	Oil production wells	3	
	Participating field area (including satellites)	18,853 acres	
	Daily production (thousands)	11,000 bbls/day	
Polaris Fast Facts	Production started	1999	
	Oil production wells	10	
	Participating field area (including satellites)	11,681acres	
	Daily production (thousands)	4,000 bbls/day	
Borealis Fast Facts	Production started	2001	
	Oil production wells	27	
	Participating field area (including satellites)	7,757 acres	
	Daily production (thousands)	19,000 bbls/day	

Location
The Prudhoe Bay field is located 650 miles north of Anchorage and 400 miles north of Fairbanks. It is 1200 miles from the North Pole and 250 miles north of the Arctic Circle. Pump Station 1, the beginning of the Trans Alaska Pipeline, is located with in the perimeter of the Prudhoe Bay field.

Source:
Page: 1

Revised: August 06

EXHIBIT 1 (page 2)



Geologic Features

The Prudhoe Bay field, like many oil fields, consists of layers of porous rock that contain gas, oil, and water. The water, being the heaviest, lies in the lower rock layers of the field. The oil lies above the water, and the gas rests atop the oil. The oil, gas, and water are held in the Prudhoe Bay field by changes in the rock type (stratigraphy) and by the tilt and faulting of the rock layers. Sandstones are porous and allow the fields' fluids to flow through them. Shales, however, act as barriers to fluid flow. Thus, whenever a sandstone layer meets a shale layer, either through faulting or as a factor of how the rock was originally deposited, the shale stops the fluid flow and the fluids are trapped.

The oil at Prudhoe Bay is trapped in the Sadlerochit formation, a sandstone and gravel structure nearly 9,000 feet underground. In some locations the oil-bearing sandstone was 600 feet thick during the field's early life. Today, average thickness of the oil bearing zone is about 60 feet.

Natural gas

The field contains an estimated 46 trillion cubic feet of natural gas (in place) in an overlying gas cap and in solution with the oil. Of that, about 26 trillion cubic feet are classified as recoverable.

Investment

The major owners have invested more than $25 billion to develop the Prudhoe Bay field and the transportation system necessary to move Prudhoe Bay crude oil to market.

Satellite Fields

Since 1998 five satellite fields have been discovered and developed within the unit boundaries of the Prudhoe Bay oil field. These fields are Midnight Sun, Aurora, Orion, Polaris, and Borealis. One of the key objectives of the field's development has been to maximize sharing of existing infrastructure, including production and support facilities. The production wells for these satellite fields are located on one of the Prudhoe production pads. The liquids are processed through Prudhoe Bay facilities.

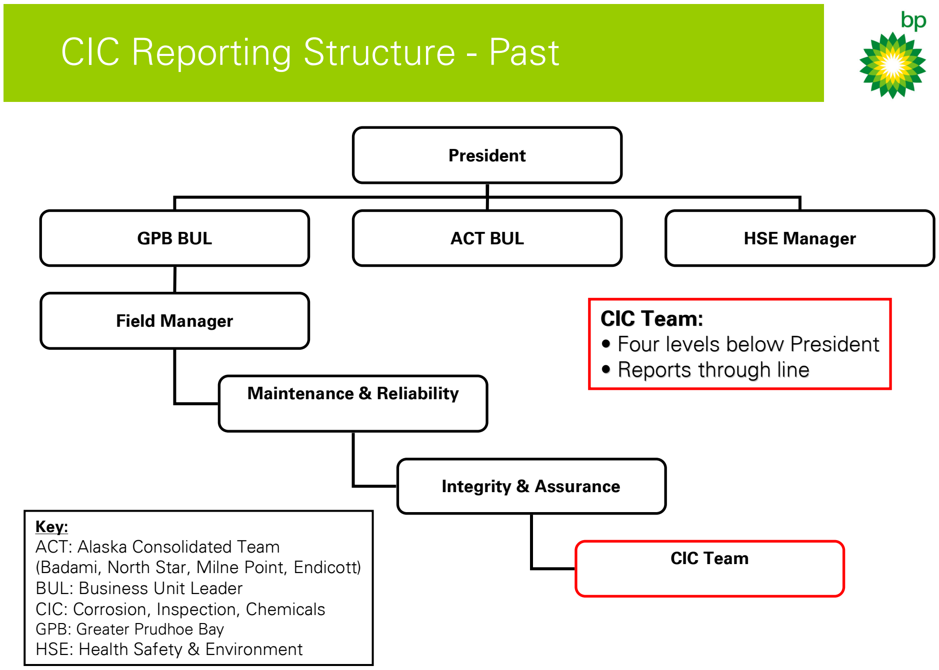
Source:
Page: 2

Revised: August 06

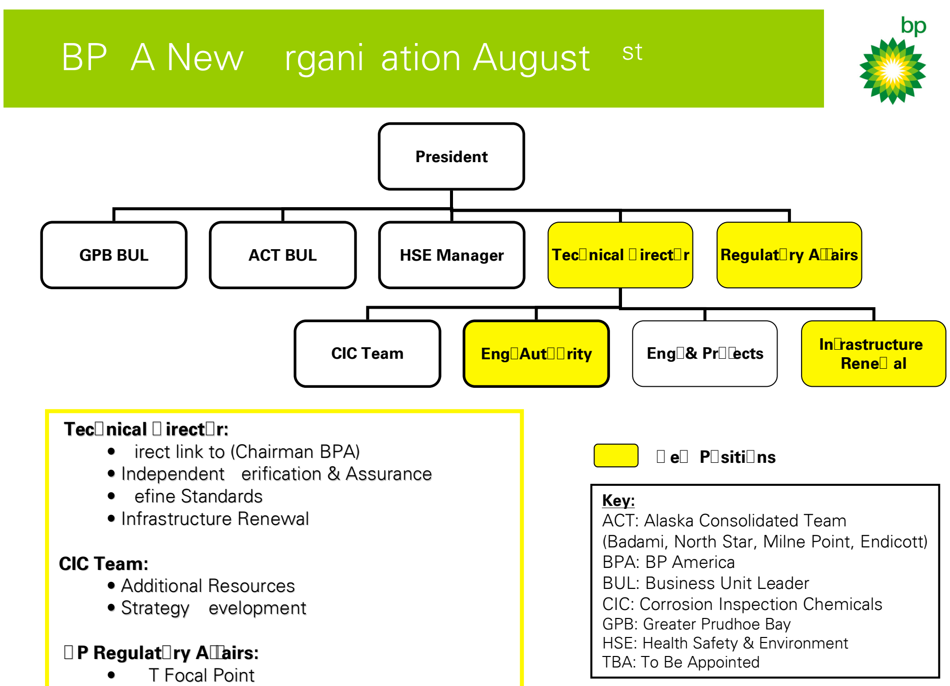
EXHIBIT 1 (page 3)

BP Exploration (Alaska)

EXHIBIT 2

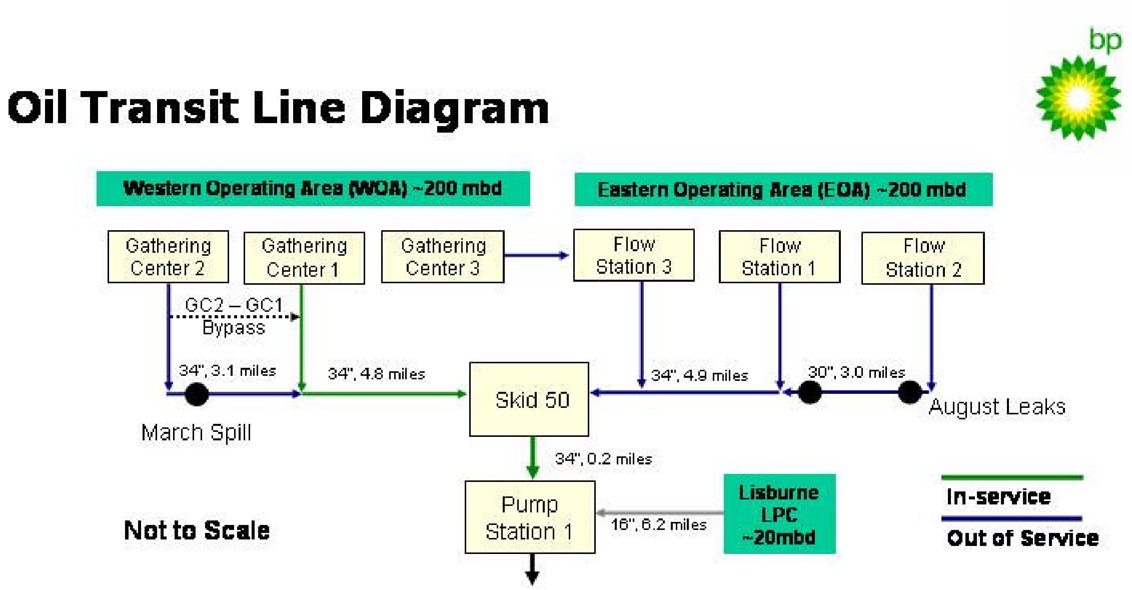


CIC Reporting Structure - Past
bp
President
GPB BUL
ACT BUL
HSE Manager
Field Manager
CIC Team:
• Four levels below President
• Reports through line
Maintenance & Reliability
Integrity & Assurance
CIC Team
Key:
ACT: Alaska Consolidated Team
(Badami, North Star, Milne Point, Endicott)
BUL: Business Unit Leader
CIC: Corrosion, Inspection, Chemicals
GPB: Greater Prudhoe Bay
HSE: Health Safety & Environment



BP A New rgani ation August st
bp
President
GPB BUL
ACT BUL
HSE Manager
Tec□nical □irect□r
Regulat□ry A□airs
CIC Team
Eng□Aut□□rity
Eng□& Pr□□ects
In□rastructure Rene□ al
Tec□nical □irect□r:
• irect link to (Chairman BPA)
• Independent erification & Assurance
• efine Standards
• Infrastructure Renewal
CIC Team:
• Additional Resources
• Strategy evelopment
□P Regulat□ry A□airs:
• T Focal Point
□e□ P□siti□ns
Key:
ACT: Alaska Consolidated Team
(Badami, North Star, Milne Point, Endicott)
BPA: BP America
BUL: Business Unit Leader
CIC: Corrosion Inspection Chemicals
GPB: Greater Prudhoe Bay
HSE: Health Safety & Environment
TBA: To Be Appointed

EXHIBIT 3



Oil Transit Line Diagram
bp
Western Operating Area (WOA) ~200 mbd
Eastern Operating Area (EOA) ~200 mbd
Gathering Center 2
Gathering Center 1
Gathering Center 3
Flow Station 3
Flow Station 1
Flow Station 2
GC2 – GC1 Bypass
34", 3.1 miles
34", 4.8 miles
Skid 50
34", 4.9 miles
30", 3.0 miles
August Leaks
March Spill
34", 0.2 miles
Lisburne LPC ~20mbd
Pump Station 1
16", 6.2 miles
Not to Scale
In-service
Out of Service

EXHIBIT 4

Fact Sheet Gathering Centers, Flow Stations

Introduction

The purpose of separation facilities (known as "**gathering centers**" on the western side of the field **GC-1, GC-2, GC-3**,and "**flow stations**" on the eastern side **Flow-1, Flow-2, Flow-3**) is to separate raw crude oil, water and gas produced from the wells into the three main components. The crude must meet certain pipeline specifications before being shipped to Pump Station 1 at the start of the Trans Alaska Pipeline System (TAPS). Each separation facility is designed to process about 350,000 barrels of raw crude oil per day. The separation facilities can also handle various amounts of gas and water. The largest gas handling facilities are Flow Station 1 and Gathering Center 1, each capable of processing 2.7 billion cubic feet of gas per day. The largest water handling facility is Flow Station 2 which can process up to 600,000 barrels of water per day.

Oil System

Raw crude produced from individual production wells located at well pads is diverted to flowlines (pipelines). The flowlines transport the raw crude to the separation facilities, where the water and natural gas mixed with the raw crude are removed. The stabilized crude is then sent to Pump Station 1, the beginning of TAPS.

Gas System

The separated natural gas is compressed, dehydrated, and transported to the Central Gas Facility (CGF) where natural gas liquids are recovered and sent to TAPS and a portion are used to make miscible injectant which is used in enhanced oil recovery. The remaining dry gas goes to the Central Compression Plant (CCP), where the majority is injected into the Sadlerochit formation. A small portion of the compressed and dehydrated produced gas is used within the Prudhoe Bay Unit as fuel gas. At GC-1 and FS-3, another portion is diverted to the "gas lift" compression plant. Gas lift is a process where recovered natural gas is re-injected into the wells to add buoyancy to the oil to help "lift" it to the surface.

Separation Facilities Fast Facts	
	Separation facilities (also called Gathering centers/ flow stations) separate natural gas and water from crude oil extracted from production wells. **There** are 6 separation facilities (3 gathering centers/ 3 flow stations) at Prudhoe Bay. Other North Slope oil fields have their own separation facilities. **Each** separation facility at Prudhoe Bay is designed to process about 350,000 barrels (14.7 million gallons) of raw crude in a day. **Each** gathering center processes an average of 70,000 barrels of oil, 1400 million cubic feet of natural gas, and 200,000 barrels of produced water each day; quantities vary from facility to facility.

Water System

The "produced" water separated from the raw crude is processed to remove oil and solids. This treatment process yields an oil stream (which is returned to oil processing equipment), a dirty water stream (which is injected into the Cretaceous formation nearly 1 mile below the Earth's surface), and a treated produced water stream (which goes to injection wells at the well pads). The treated produced water injected into the formation supports a field-wide waterflood program designed to maintain reservoir pressure and "sweep" crude oil from injection wells toward oil production wells.

EXHIBIT 5

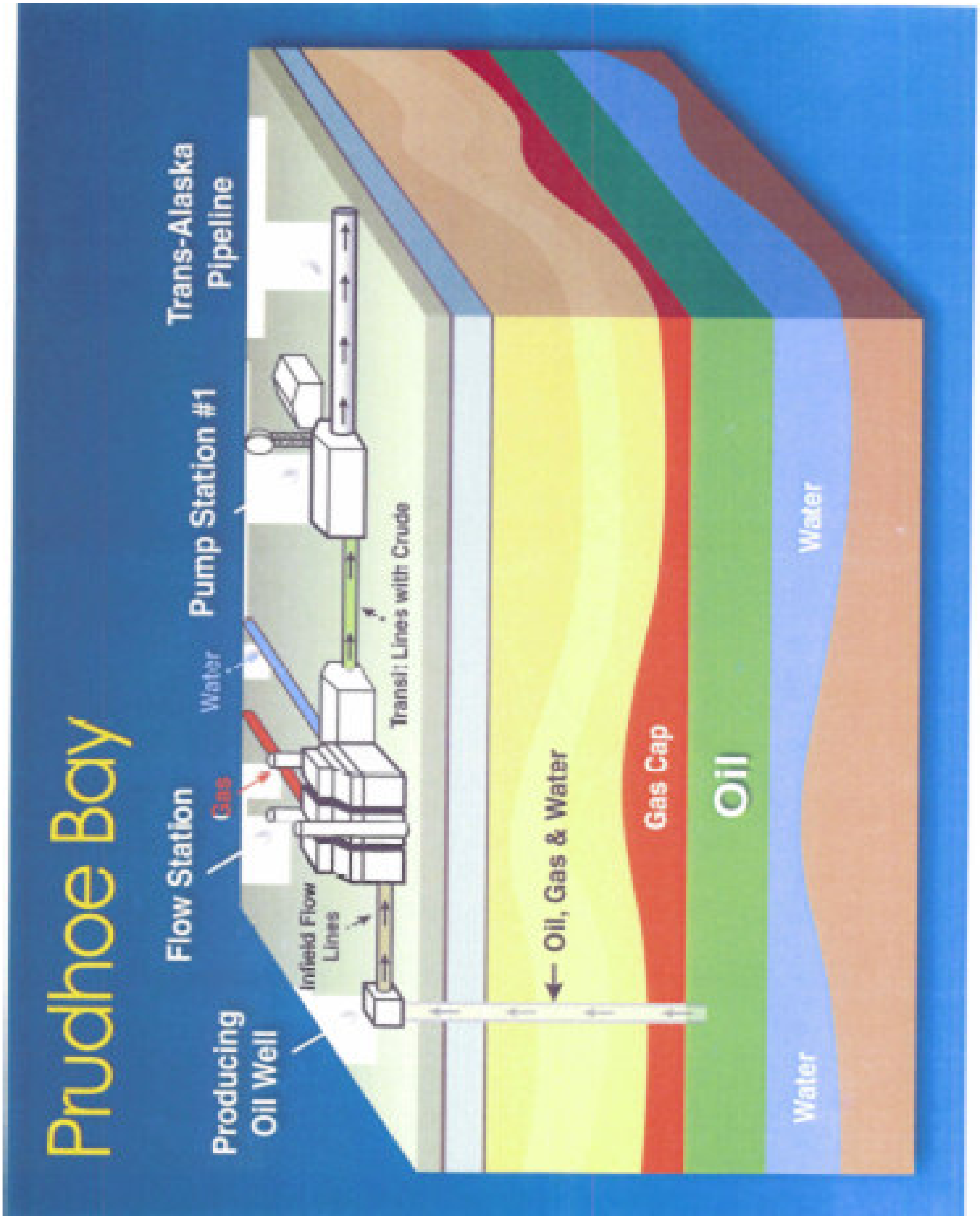

Prudhoe Bay
Producing Oil Well
Flow Station
Gas
Water
Pump Station #1
Trans-Alaska Pipeline
Infield Flow Lines
Transit Lines with Crude
Oil, Gas & Water
Gas Cap
Oil
Water
Water

EXHIBIT 6

Prudhoe Bay Corrosion Spend Versus Production

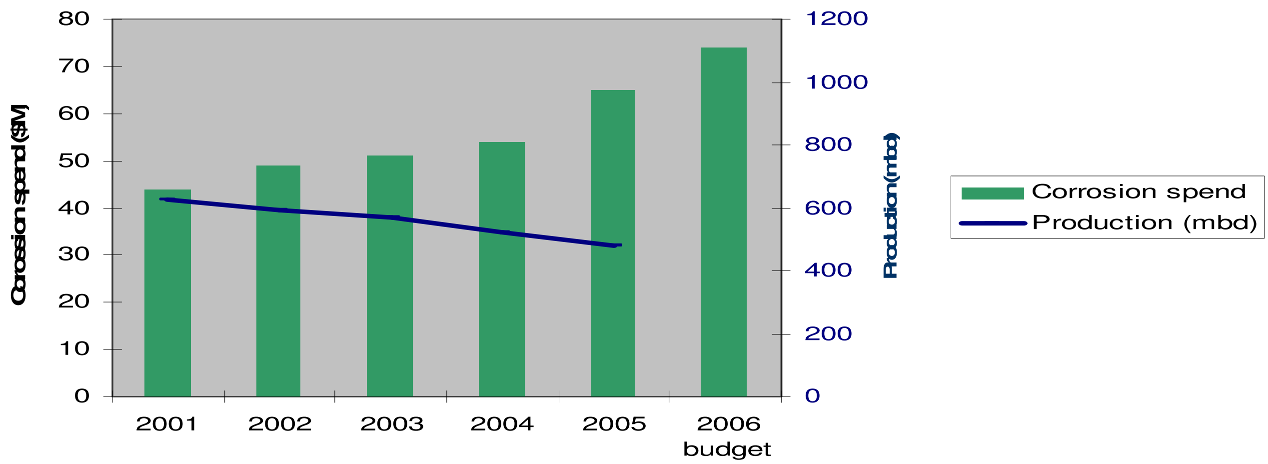


EXHIBIT 7

Diagram of Inhibitor Injection Rates

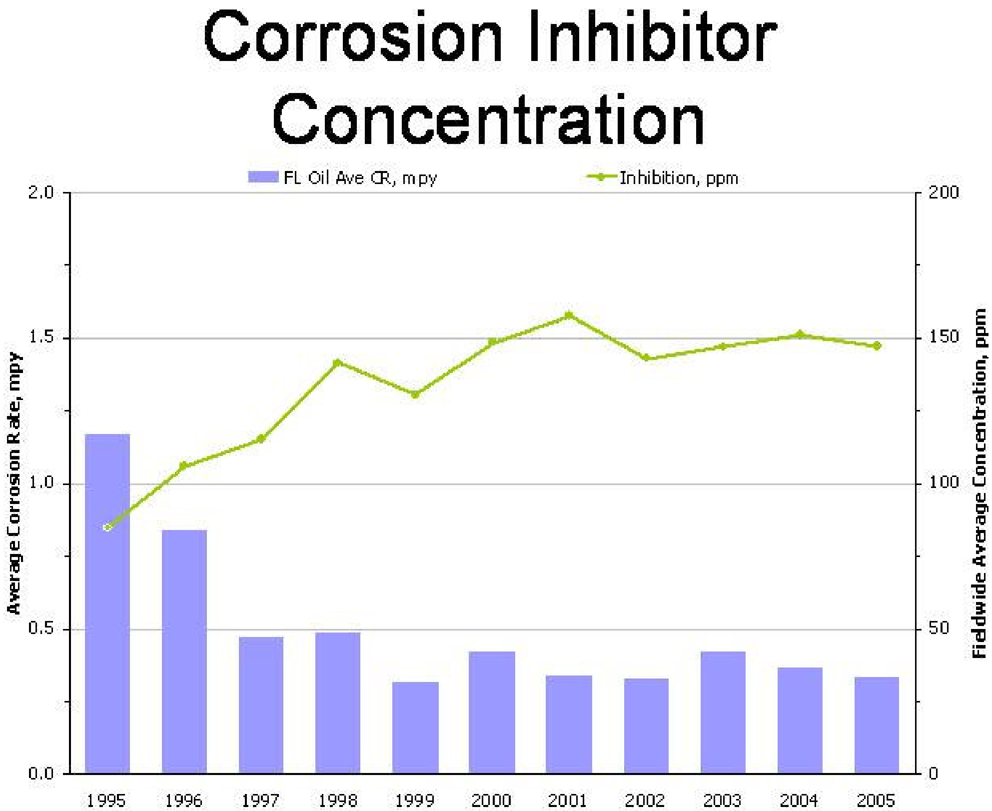
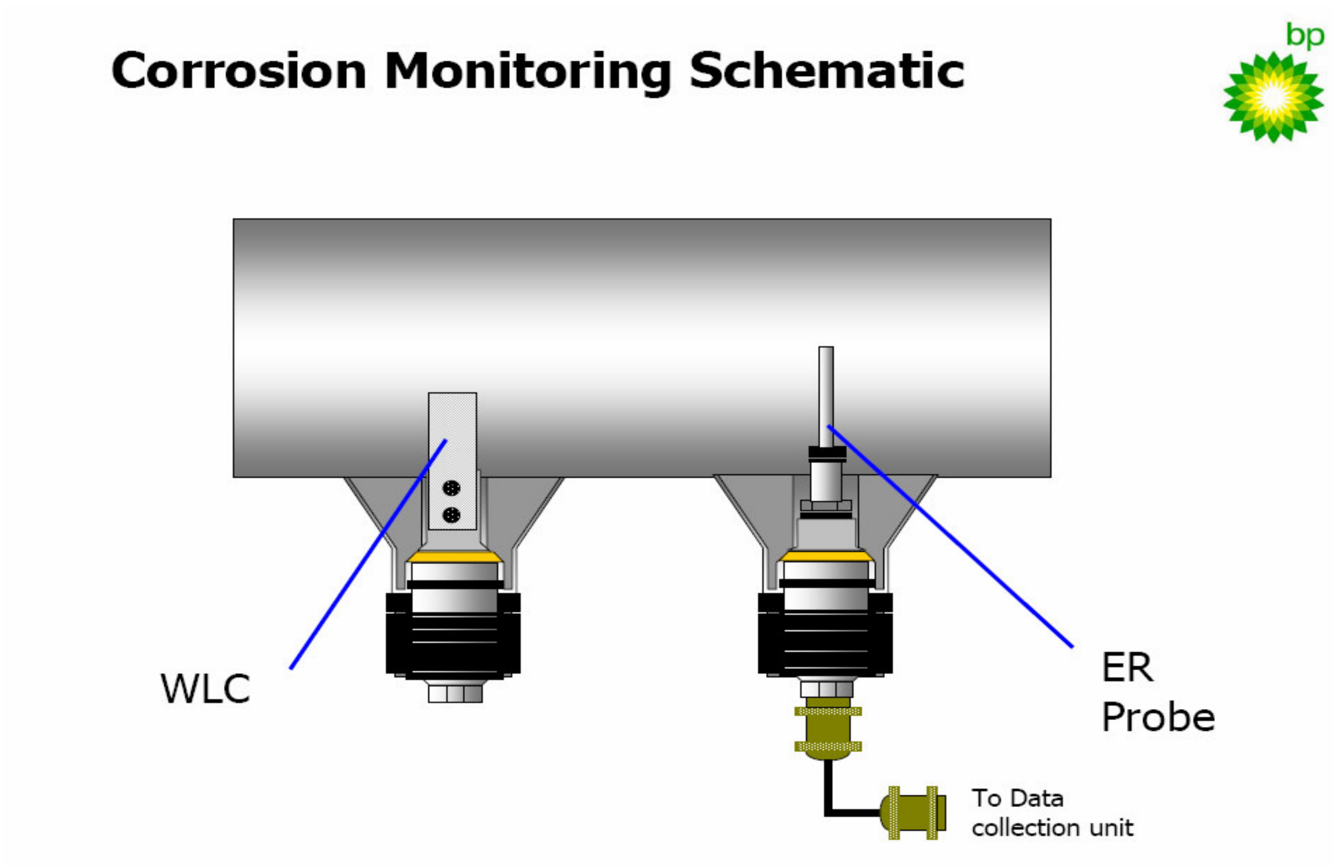


EXHIBIT 8



WLC – Weight Loss Coupon ER – Electrical Resistance

Coupon monitoring is a method that involves exposing a sample of the pipeline material (the coupon) to conditions within the pipe for a given duration, then removing the specimen for analysis. Material loss observed over the exposure period is expressed as corrosion rate.

EXHIBIT 9

Inhibitor Research Program